BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING SETTING FORTH SCOPE OF PHASE 2

I. Summary

This ruling specifies the scope of further interagency efforts in Phase 2 of our demand response rulemaking. We are keenly aware that the decisions already issued impose a significant implementation, evaluation, and monitoring workload on all active parties and participants, and have considered that reality in setting forth a scope for further activities.

Phase 1 resulted in a statewide pricing pilot for residential and small commercial customers and four demand response programs and/or tariffs for large commercial, agricultural, and industrial customers. In this successor phase, we build on this foundation and opt to spend the remainder of this proceeding exploring issues that we view to be a necessary prelude to longer-term demand response development. Our key focus will be developing an analysis framework for use in the respondents' business cases for possible widespread advanced metering infrastructure deployment. This will not prejudge the issue of advanced metering infrastructure deployment, because we intend to insure that

the analysis framework includes an assessment of the costs and benefits of different strategies to install advanced interval meters as well as viable alternatives.

Phase 2 will not develop an actual advanced metering deployment business case. Instead, we propose to focus on how the advanced metering business case should be performed, including determining appropriate categories of costs and benefits to be considered. We contemplate that the actual analysis of business case plans will be filed in separate applications in the second quarter of 2004, when the preliminary results from the small customer pilot tests and critical peak pricing (CPP) tariffs for larger customers will be available.

As a fundamental element of our examination of this issue, we will also consider two related issues essential to the evaluation of this analysis framework: (1) revisions to the standard practice manual (SPM) methodology necessary to thoroughly evaluate additional demand response programs and hardware deployment; and (2) since we will require that any proffered business case ultimately include an analysis of alternatives to full-scale deployment of advanced metering infrastructure, we will require the parties to examine how air conditioner (AC) cycling can be presented as such an alternative (Decision (D.) 03-03-036, Ordering Paragraph 7).

In addition to the key business case focus, we will consider in Phase 2 a series of implementation issues identified in our previous decisions or that we have become aware of post-adoption of these decisions. These issues are identified in Section II.B. of this ruling.

After we have completed this discrete set of tasks in Phase 2, we intend to close this proceeding and issue a new demand response rulemaking that will build upon our past interagency efforts, as it addresses forward-looking issues.

To that end, this ruling seeks comments on our proposed scope for Phase 2 of this proceeding. After receiving comments, the Assigned Commissioner will issue a final Phase 2 Scoping Memo with an anticipated schedule for meetings and/or hearings, if necessary.

II. Phase 2 Scope

The primary issue to be addressed in Phase 2 is the development of an analysis framework for the ultimate presentation of the utilities' business cases, including necessary examination of the SPM modifications and AC cycling scenarios as alternatives, as discussed above. In addition, work will continue on several ongoing projects that began in Phase 1, as described more fully below.

A. Preparation for Consideration of Advanced Metering Business Cases

When we first opened this proceeding, we contemplated addressing both demand response program and tariff issues as well as the potential for mass deployment of advanced metering infrastructure. We are now more than one year into this proceeding, and have so far focused primarily on demand response options and not metering infrastructure issues.

Although we continue to recognize the linkage between metering infrastructure issues and the ability of utilities to deploy demand response as a resource, we also recognize that the potential value (and cost) of deployment of advanced metering extends far beyond demand response. Many aspects of advanced metering infrastructure development are only tangentially related or not related at all to demand response. For example, advanced metering affects outage detection, interface with billing systems (and thus customer service), and utility labor deployment, to name a few issues.

In Phase 1 of this proceeding, Pacific Gas and Electric Company (PG&E) filed a draft business case plan for advanced metering deployment for illustrative purposes. Our proposal for Phase 2 is to build upon that effort and fully develop the framework for how the Commission should evaluate a business case for deployment of advanced metering and then require utilities to submit a substantive case in a future proceeding / application.

We propose to return our focus to an examination of the costs and benefits of such a system, as outlined in the initial order instituting rulemaking for this proceeding. Those were summarized as follows (with new elements added):

Potential Costs

- Typical hardware and software costs for advanced metering infrastructure (AMI) metering systems
- Installation costs
- Operations and maintenance costs
- Integration costs with utility billing systems

Potential Benefits

- Value of avoided costs of electricity purchases during peak times or events
- Avoided transmission and distribution upgrade costs
- Benefit of any net reduction in air emissions (and other environmental externalities)
- Value to customers of more timely and accurate information about electricity use
- Value to customers of more timely and accurate bills
- Associated customer service cost savings

- Lower electric bills for some customers
- Lower technology costs produced through bulk meter purchases
- Better outage detection
- Operational cost savings
- Labor cost savings
- Better meter functionality/equipment modernization
- Potential for Federal investment tax credits

A more complete description of these factors is contained in Attachment A, a draft document prepared by the Energy Division and California Energy Commission staff proposing a framework to evaluate these and other categories of costs.

Parties should include in their comments filed in response to this ruling their views on the proposed scope and method to conduct the business case analysis for AMI.[1]

1. Update of the SPM

This effort was identified in Phase 1 as a need, in order to fully account for the costs and benefits of demand response programs and/or dynamic pricing rates. It is our understanding that this issue came up most in the context of Working Group (WG) 2, since WG 3, in developing a pilot program, was less focused on cost-effectiveness as an issue. We believe there are two inter-related issues: revising the methodology itself, and development of protocols for creating the inputs required by the cost effectiveness tests.

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[1] See Attachment A.

We acknowledge that modifying the SPM methodology is equally relevant to cost-effectiveness analysis for large and small customers, but this task does not seem likely to be accomplished in a working group setting. Instead, we suggest that one or more of the utilities, with input from other working group participants, hire a consultant to propose modifications to the SPM methodology. The consultant's report can then be presented to the working groups for review and discussion. If all parties agree with the recommendations, the Commission may not need to formally adopt any changes and can instead consider the consultants' modifications a working document; if there are disagreements, then we can address the proposed changes more formally in this docket, through comments and ultimately a decision, if necessary.

Developing protocols for the inputs required by the cost-effectiveness tests involves upgrading or replacing assumptions that were formerly described as avoided costs. In the current hybrid market structure, it is not at all clear that the practical implications of avoided cost are the same as they once were. For example, in 2003, as utilities have returned to procurement they face hourly procurement decisions based on purchases in California Independent System Operator markets, operating their own utility retained generation, spot market purchases, and exercising call option contracts previously entered into. Similarly, from a planning perspective is the avoided cost determined from the physical attributes of various generation technologies, long-term projections of market prices, costs of multi-year contracts resulting from utility Request for Proposals, or some other sources? Updating the cost effectiveness tests for demand response may require resolution of these input value issues through some sort of standard protocols as much as modifying the SPM tests themselves.

This is important work because it is likely that at least for some business cases it may be necessary for utilities and/or parties to develop new methodologies to value costs or benefits not normally included in an SPM analysis. For example, new methods may need to be developed to value the public benefits of reducing the risks of outages (during periods of peak congestion or rapid increases in wholesale prices), reducing the length of outages, and/or quantifying the value of increases in customer service and potential costs.

2. AC Cycling

The analysis framework for demand response needs to establish parameters for comparing AC cycling with other price-responsive demand options. This side-by-side comparison of AC cycling programs versus price-responsive demand programs should examine a range of available AC cycling technologies, different programmatic approaches, and other operating, economic and policies attributes. Clearly, we need a means to compare those technologies limited to implementation of one or two emergency load shedding programs with technologies that can support multiple dynamic pricing and load shedding programs. We understand that each utility may not have the same experience with the full array of AC cycling options, and that making comparisons will be a challenge. In Phase 2, we expect the development of the analytical framework for making this alternative comparison. Below we provide a starting point for the attributes to consider in this side-by-side comparison.

Attributes for Comparing AC Cycling
with Price-Responsive Demand Options

- Cost and Cost Effectiveness
  - What is the cost/megawatt of demand reduction?

  - Are incentives fixed, linked to program operation or customer load reduction?
- Demand response potential
  - Which customers can and cannot participate in both options?
  - Estimate the capacity and energy savings potential for each option

- Equity
  - Are customers paid to participate or paid for the value of their demand reduction?
  - Are incentives consistent with other demand reduction programs?
  - Are incentives consistent with underlying rates?
- Operations
  - Are there seasonal, time of day or other operating restrictions?
  - What capability exists to address both energy management and reliability objectives for each option?
- Customer Choice
  - Who controls the customer loads?
  - Can customers tailor their demand response to fit their budget and lifestyle preferences?
- Technology
  - Utility versus customer ownership of devices required for each program
  - Compatibility with building automation systems
- Policy
  - Reliability of peak-savings from each option
  - Pay for performance versus pay for participation
  - Compliance effort needed – self-regulating versus ongoing monitoring and enforcement
  - Compatibility between conservation, efficiency, and demand response objectives

B. Ongoing Issues

In Phase 2, we will continue working on several projects that began in Phase 1, but were not resolved in either D.03-03-036 and D.03-06-032.

1. Real Time Pricing (RTP) Tariff Development

Completion of a viable RTP tariff proposal will provide customers a new and important option, to be included in our ultimate mix of program offerings.

Parties are currently exploring alternatives for RTP design features in the WG 2 process, as described in D.03-06-032. That decision also authorized expenditures on this effort up to a $2.8 million cap. By the end of Phase 2, we expect to have before us a fully detailed real-time tariff proposal that can be adopted for use by large customers for the summer of 2004. We expect at this point that the development of this tariff will proceed within the context of WG 2. If parties disagree and/or believe that approval of the RTP tariff will require evidentiary hearings, they may comment on this issue and indicate specifically what issues require such treatment and why.

2. Agricultural Customer Participation

Phase 1 left unresolved a series of issues related to agricultural customers. First, deployment of advanced meters for PG&E agricultural customers lags behind that of Southern California Edison Company and San Diego Gas & Electric Company. Since Assembly Bill (AB) 29 X funds are no longer available, we wish to explore options for correcting this disparity. Second, we also wish to explore how to expand opportunities for additional agricultural customer participation in the CPP tariff and the demand bidding program. Parties should include in their comments their views on the optimal way these issues can be addressed in Phase 2.

3. Revenue Shortfall Recovery

In Phase 1, the Office of Ratepayer Advocates made a proposal for alternative recovery of revenue shortfalls due to demand response programs. That proposal remains to be addressed. In compliance with D.03-06-032, Ordering Paragraph 19, staff held a workshop and the utilities made proposals for recovering net revenue losses from participation in the voluntary CPP tariff from within the class that caused the losses. We intend to review these proposals in this proceeding. Parties who believe that such review requires evidentiary hearings shall identify those areas in response to this ruling.

4. California Payphone Association (CPA) Demand Reserves Program (DRP)

Implementation efforts are ongoing to resolve issues related to the CPA DRP. Transfer of dispatch from California Department of Water Resources to the investor-owned utilities (IOU) must be accomplished either through agency agreements or Commission order. Product development for supplemental energy and ancillary services (non-spin) for both utility bundled and direct access customers also remains to be accomplished.

5. Miscellaneous Implementation Issues

In addition, we are aware of several implementation issues that have arisen during the review of advice letters implementing the specific programs authorized in D.03-06-032. These include:

- Uniformity in the provision of metering services for those customers with an AB 29 X-equivalent metering system
- Installation of AB 29 X-equivalent metering systems for new IOU customers added since the AB 29 X conversions that took place between fall 2001 and summer 2002

- Uniformity of the linkage between the existence of AB 29 X equivalent metering systems and automatic transfer of such bundled service customers to a Time of Use rate

We expect that these "cleanup" issues can be resolved relatively easily since they do not involve major policy extensions of our previous decisions. We look forward to suggestions for how to resolve each of these issues, and require each respondent to provide its proposal in comments on this draft ruling.

III. Phase 2 Utility Cost Recovery

For Phase 2 efforts such as the hiring of a consultant or the further development of AC cycling program proposals, costs, and benefits, we propose that the utilities continue to record and track these administrative costs in their Advanced Metering and Demand Response Accounts. The full commission will still need to ratify the reasonableness of these expenses prior to authorizing the utilities to actually recover these costs.

IT IS RULED that any party wishing to comment on any aspect of the proposed Phase 2 scope, as discussed in this ruling, may do so no later than October 6, 2003 by filing and serving (electronically) their comments.

Dated September 19, 2003, at San Francisco, California.

/s/ MICHAEL R. PEEVEY	/s/ LYNN T. CAREW	/s/ JOSEPH R. DEULLOA By LYNN T. CAREW
Michael R. Peevey President	Lynn T. Carew Administrative Law Judge	Joseph DeUlloa Administrative Law Judge

CERTIFICATE OF SERVICE

I certify that I have by mail, and by electronic mail to the parties to which an electronic mail address has been provided, this day served a true copy of the original attached Assigned Commissioner and Administrative Law Judges Ruling Setting Forth Scope of Phase 2 on all parties of record in this proceeding or their attorneys of record.

Dated September 19, 2003, at San Francisco, California.

/s/ JANET V. ALVIAR
Janet V. Alviar

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at

(415) 703-2074, TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.

Attachment A in Peevey,Carew DeUlloa Ruling re Scope of Phase 2